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Evaluation of flexible CCS-CHP concepts and systems – CCSP Task 2.1.1. Status report 1

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Key words: CCS, flexibility, CHP

Abstract

A cash flow model of a case CHP system has been built and an optimisation problem defining the most profitable emission reduction technologies and load factors for the included plants has been formulated. The case CHP system consists of a coal- and a gas-fired CHP plant, a biomass-co-firing circulating fluidised bed CHP plant as an optional investment and an oil-fired district heating plant. The optimisation problem has been solved for four static market scenarios comparing two emission reduction requirements against the business-as-usual situations. When -50 % CO_2 emissions were required, CCS emerged as a profitable emission reduction technology for the coal-fired CHP plant in the market scenario with peak electricity price and high heat demand. Assuming an emission reduction requirement of -80 % compared to business-as-usual situation, CCS was widely applied in the system.

Literature references on the flexibility of CO_2 capture in CHP environment are few. Be that as it may, more research results are available for CCS flexibility in power production. Based on a literature review, capture of CO_2 in general does not seem detrimental to a power plant's start-up times, ramp rates, part-load efficiencies and minimum load levels. Oxy-combustion plants seem to suffer from slower ramp rates and longer start-up times, however. It will be interesting to assess the possible positive effect of flexible use of CO_2 capture to the CHP system's net profitability during the Phase 2 of the work. However, further optimisation model development is still necessary.

Espoo, January 2015

Preface

This is the first report from the Task 2.1.1. of the CCSP program. The work in this task is ongoing, and concerns the techno-economic assessment of CO2 emission reduction technologies in CHP systems. Optimisation modelling, technology review and market scenario assessment are carried out and combined in the research, giving the work a wide and ambitious focus. Executed at VTT, the work includes input from ÅF Consulting. The steering group consists of representatives from Gasum, Fortum Oyj, and Helen Oy.

Espoo 8.1.2015

Authors.

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1 Introduction

In addition to driving the energy prices to higher levels, augmented climate mitigation policies are likely to promote more wind and solar power investments to the energy systems. Increasing the share of such intermittent renewable power will cause a demand for balancing power, seen as stronger fluctuations in the electricity spot prices.

Due to high investment costs, carbon capture and storage (CCS) systems are often regarded as an emission reduction option for base load utilities. Given the demand to set a more stringent cap on CO_2 emissions in the European Union and taking into account the possibility of more volatile electricity markets in the future, the economic performance of CO_2 capture in the Nordic combined heat and power (CHP) production environment calls for research.

The flexibility of CCS, i.e. the ability to adjust according to rapid changes in electricity demand, has earned attention in the scientific community during past years. Technical parameters describing the flexibility of power production can therefore be assessed based on literature review. Fewer results have been published on the flexibility of CO_2 capture in CHP production systems, however.

Identifying the influences of CCS integration to CHP systems are essential in the Nordic energy production infrastructure with high rate of urban CHP production. This study assesses whether CO_2 capture systems can be operated flexibly in a CHP production environment. The work serves to contribute to the knowledge on technical interaction of CHP production with CO_2 capture and the economy of flexible CO_2 capture in CHP production systems compared to alternative emission reduction technologies.

2 Goal

This work progresses in two subsequent phases, during which necessary material is reviewed and the needed modelling tools are developed. The objective of the first phase of the project is to establish a merit order of different emission reduction technologies for an urban environment with combined heat and power infrastructure. Towards this end, comparable prices of different emission reduction solutions suitable for the environment are specified. The suitability of these solutions for operating in different market situations is then assessed. The techno-economic material for the emission reduction technologies is based on the previous studies at VTT under the CCS Finland and the CCSP programmes.

The CHP system within the scope of the first phase of the work (Phase 1) consists of a CHP network of a large city, including several CHP production units and additional peak heat production units. During Phase 1, the system is assumed to be operated under energy prices reflecting possible situations in the current markets. The costs of emission reduction technologies along the whole production value chain, from fuel preparation to power plant are estimated and the merit order of the alternative solutions is determined accordingly in the different market situations. The technologies are evaluated based on case matrix composing of market scenarios and emission reduction targets. Different market situations are investigated separately, as the costs of emission reduction solutions may vary significantly, similarly as do their viability and profitability. Several emission reduction targets are considered because different emission reduction solutions have unequal CO_2 reduction potentials and all targets might not be able to be achieved with all technologies.

The objective of the second phase (Phase 2) of the work is to find out what is the role of CCS installations in CHP systems when a high demand for balancing power is assumed under ambitious CO_2 emission reduction targets. The economy of flexible CO_2 capture systems will be assessed in a CHP environment under unpredictable energy market price fluctuations.

To arrive at the goals of Phase 2, the performance of CO_2 capture technologies are examined by hourly level modelling of the CHP system. Future production and demand scenarios are used, assuming a high share of intermittent renewable power being fed to the grid. The research question is addressed with a help of an optimisation dispatch model developed during the project.

During the writing of this first status report of the task 2.1.1 the work is progressing towards the beginning of phase 2. The following report from Phase 2 is meant to build upon this report.

3 Description of the studied problem

3.1 Electricity markets and the assumed scenarios

Electricity is produced concurrently with consumption. Therefore, the production must respond to the demand with as low latency as possible. The electricity spot prices over one week in Finland, taken from the Nordpool website[1], is presented as an example in Figure 1. During the presented week in October 2014, the hourly electricity spot prices varied from below 10 €/MWh to over 60 €/MWh. The peak values occurred in the evenings after the office hours. Electricity had the lowest value during the early hours after midnight. During the weekend, the price variations were lower. On top of the obvious effect of consumer behaviour in the electricity market value, the availability of renewable electricity from wind, water and solar sources influence the market value of electricity. Furthermore, the prevailing fuel prices are reflected in the electricity markets. The systemic complexity of production and consumption of electricity therefore causes unpredictable behaviour of the markets. Increasing share of intermittent renewable power is likely to induce higher price variations.

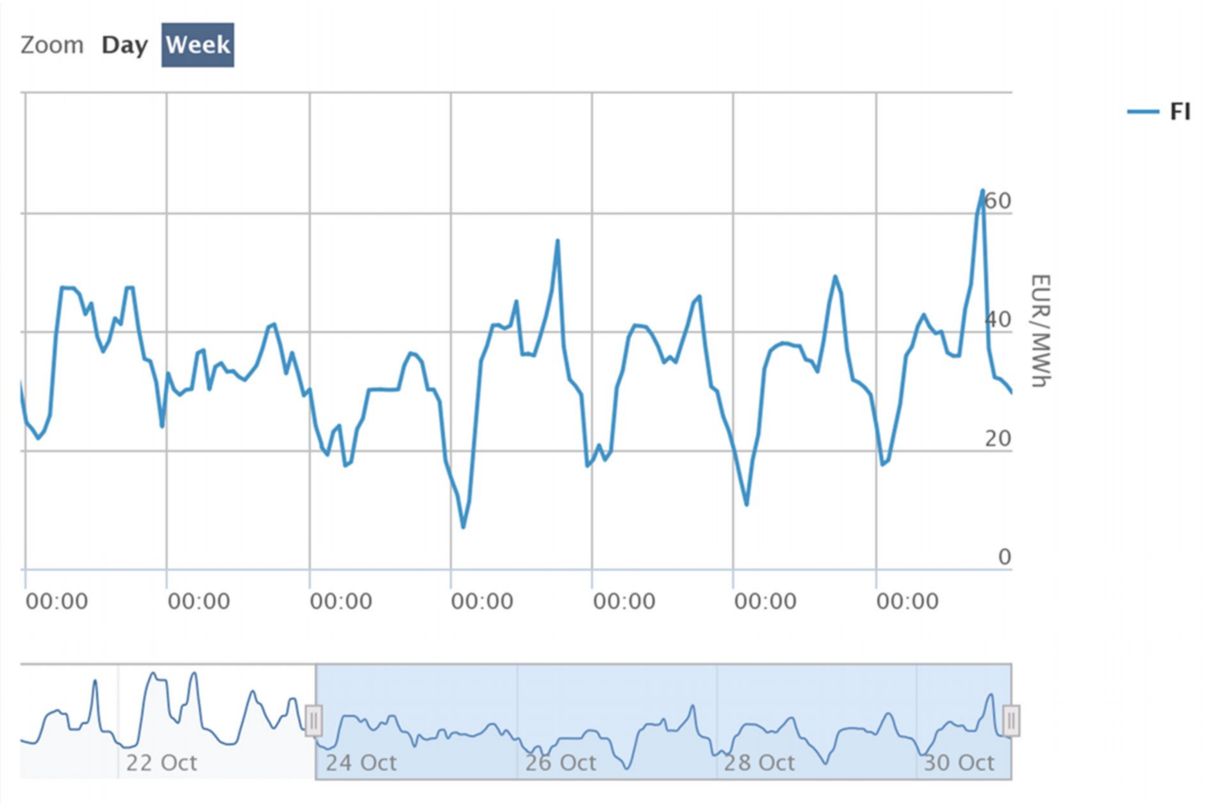

Figure 1. Nordpool electricity spot price in October 2014.

The price of electricity also depends on country specific taxation and subsidies. A subsidy of 0.002 €/kWh is granted for electricity from biomass combustion in Finland.

During the Phase 1 of the project, the merit order of selected emission reduction technologies were studied in static market scenarios. Presented in Annex 2, the four

[1] http://www.nordpoolspot.com

scenarios reflect low and peak electricity prices during both high and low heat demand in the CHP network.

3.2 The case district heat / CHP system

The consumer facilities connected to a district heating network cause a heat demand that has to be fulfilled by one or several of the connected heat producing units. Similar to electricity demand, the heat demand fluctuates during a day. However, the actual load demanded of the district heating (DH) plants and CHP plants is levelled by large heat accumulators incorporated into the network. Therefore, district heat has a fixed local market price (€/kWh) on a given season, while the electricity produced by the CHP plants has a more volatile value in the non-regional markets. In Finland, a tax of 0.01 €/kWh is levied from sold heat from fossil fuels.

The case CHP network consists of one DH plant and three CHP plants. The DH plant uses oil as a fuel. The CHP capacity consists of a natural gas fired combined cycle gas turbine (NGCC) plant, a pulverised coal fired (PC) plant and a circulating fluidized bed (CFB) combustion plant, able to co-fire high shares of biomass fuels. The technical specifications, i.e. overall efficiencies and heat and power production capacities, of the four plants that form the case CHP network are presented in Annex 3 - Annex 6. Also other relevant techno-economic parameters are given for the plants and the associated emission reduction technologies as described in chapter '3.2.1 The emission reduction technologies'.

3.2.1 The emission reduction technologies

Burning fossil fuels in the DH and CHP units of the case system causes unwanted CO_2 emissions. Each production unit in the case DH network can have a set of alternative emission reduction technologies. Furthermore, different operating modes for a given plant equipped with a given emission reduction technology can be assumed. Such operating modes regarding CCS technologies are further discussed in chapter '3.3 Flexibility of CO_2 capture in a CHP plant', serving as material for the work on Phase 2.

The main emission reduction technology options assumed in the Phase 1 of the work were fuel switching and CCS.

The PC CHP plant has the option to co-fire pellets or biomass or apply retrofitted CO_2 capture. The calorific share of pellets would amount to 7 % and the share of co-fired biomass would amount to 40 % respectively. These emission reduction technologies for the PC CHP plant are referred to as PEL-7%, BIO-40% and CCS further in the report. Techno-economic specification assumed for the above emission reduction technologies are presented in Annex 3.

Regarding the NGCC CHP plant, the assumed emission reduction technologies are retrofit CO_2 capture or co-firing of biogenic synthetic natural gas (bio-SNG) with a calorific share of 50 %. The techno-economic parameters for the emission reduction technologies, referred to as CCS and BioSNG-50%, of the case NGCC plant are given in Annex 4.

The case CFB CHP plant is an optional new-built facility. Therefore, the plant is ether not invested in and not built at all or is introduced to the CHP network as a new-build. If built, the plant co-fires forest biomass (40 % calorific share) with coal. The techno-economic assumptions for these two options ('Not included' or BIO-40%) are presented in Annex 5.

Finally, the case DH plant has an option to reduce its emissions by replacing fossil fuel oil with pyrolysis oil. The pyrolysis oil can be either co-fired with a calorific share of 5 % (further referred to as 'BIO-OIL 5%') or the fossil fuel oil can be completely replaced (further referred to as 'BIO-OIL'). For techno-economic parameters regarding the DH plant, see Annex 6.

3.3 Flexibility of CO_2 capture in a CHP plant

Throughout the presented work, the term ‘flexibility’ refers to a plant’s ability to adjust its heat and power production efficiencies and ramp times in a response to hourly changes in electricity markets. Brouwer *et al*. (2013) define the main parameters contributing to the flexibility as part-load efficiency, minimum load level, ramp rate, and startup time. During Phase 2, the work will focus on the flexibility of CO_2 capture in a CHP environment. Based on literary review, material towards this purpose is presented here. The studied CO_2 capture technologies are post-combustion capture and oxy-combustion.

Besides normal operation with CO_2 capture running on full capacity, CHP plants with CO_2 capture can have several operating modes for different market situations. Post combustion CO_2 capture unit can be bypassed in pursuit of responding to peaking electricity prices. Alternatively, solvent buffer storage tanks can be applied, enabling the CHP plant to momentarily bypass the solvent regeneration stage. This would allow for higher electric efficiency during peak hours while the CO_2 capture would remain uncompromised. Similarly, buffer storage for liquid oxygen would enable an oxy-combustion CHP plant to switch the air separation unit (ASU) to temporary stand-by during peak hours of electricity demand.

Although creating possibilities for different operating modes such as described above, the CO_2 capture units can have negative effects on the flexibility parameters of a CHP plant, discussed further in ‘3.4 Key flexibility parameters of CO_2 capture’. Based on results published by Domenichini *et al*. (2013), the start-up times of plants with post-combustion capture unit can be higher than for “non-CCS” plants due to heat-up of the stripper column. Regarding oxy-combustion, the ASU is the main constraint on the plant flexibility, due to high minimum load level of the coldbox and its slow ramp rate. The start-up time of the ASU is especially lengthy.

3.3.1 Post-combustion: Capture bypass

A CHP plant with a post-combustion CO_2 capture unit has the option to vent the flue gasses in pursuit of responding to peak electricity demand. As the flue gasses are vented, the CO_2 capture unit is bypassed and the steam otherwise consumed by the solvent regeneration stage is redirected to the steam cycle for electricity production. Making high amount of extra steam available suddenly to turbine stages the efficiency and the ramp up rate of electricity production can ideally be increased. However, the steam cycle needs to be designed to be able to take all the additional steam during the venting of CO_2. This in turn can cause non-optimal conditions during normal operation. Domenichini *et al*. (2013) suggested a low pressure turbine for the bypassed steam could address these issues.

Naturally, besides being completely bypassed, the post-combustion CO_2 capture system can have the option to be operated at part load.

3.3.2 Post-combustion: Solvent storage

Buffer storages for both CO_2 lean and CO_2 rich solvent enable momentary decoupling of solvent regeneration from the actual CO_2 capture in post-combustion capture systems. The spent solvent can then be later regenerated into CO_2 lean solvent storage during low market value of electricity. In turn, the solvent regeneration stage could then be set to stand-by or operated at partial load during peak electricity demand. The storage sizes would set the feasible time limit for stand-by of regeneration stage at full electric production. Based on Domenichini *et al*. (2013) approximately 2 hours can be regarded as a good assumption for such time limit.

If the limits of buffer solvent storages are met and the plant needs to return to normal operation at full capacity and CO_2 capture, simultaneous replenishing of the CO_2 lean solvent storage would imply an oversized solvent regeneration and CO_2 compressor capacity. Otherwise, the stored CO_2 rich solvent can be regenerated only during hours of lower demand. As the sizing of regenerator and CO_2 compressor stages have strong implications to capital costs (Domenichini *et al*. 2013) this question would have to be answered through case-by-case optimisation.

3.3.3 Oxy-combustion: Oxygen storage

The ASU consumes electricity and has a significant impact on the net electric output of an oxy-combustion plant. By applying buffer storage for the liquefied oxygen, the ASU can be operated temporarily at partial load, increasing the net power output during hours of high electricity price.

The cold box of the ASU has a long start-up time and a high minimum operating load. This limits the technical viability of setting the ASU at temporary stand-by during peak demand of electricity. Some buffer storage capacity for liquid oxygen would in any case likely mitigate the impact of the ASU to an oxy-combustion plant's flexibility.

3.4 Key flexibility parameters of CO_2 capture

Unless otherwise stated, the following flexibility parameters are given for condensing power plants with CCS.

3.4.1 Part-load electric efficiency

Brouwer *et al*. 2013 report 2 – 4 % electric efficiency penalty for PC plants with post combustion CO_2 capture operated at 50 % load compared to efficiency at full load. The efficiency penalty is a little lower for NGCC CCS plants, amounting to 1 – 3 % in comparison. An oxy-combustion plant has similar part load efficiency penalty as a PC plant (Domenichini *et al*. 2013).

3.4.2 Minimum load level

Considering plants with post-combustion CO_2 capture, the minimum load factor of the power plant should not be affected by the capture unit according to Brouwer *et al*. (2013). The minimum load level is 25 – 35 % for PC plant equipped with post-combustion CO_2 capture and 40 % for NGCC plants respectively. A packed absorber column has a minimum operating load of some 30 % of design mass flow rate. However, parallel compressor trains are needed to allow low material flows (IEAGHG 2012).

The minimum operational load of the ASU (40 - 60 %) can dictate the minimum load level of an oxy-combustion plant. The ASU also needs parallel compressor trains to reach load levels of below 70 % (Domenichini *et al*. 2013).

3.4.3 Ramp rate

PC power plants with post-combustion CO_2 capture have ramp rates of 3 – 5 %/minute, while those of NGCC CCS plants are 5 – 7 %/minute (Brouwer *et al*. 2013). The ramp rate does not behave completely linearly, being slightly faster at loads below 90 %.

The ASU has in general a slower ramp rate (3 %/minute) than the oxy-fuel plant would have in air-firing mode (Domenichini *et al*. 2013).

3.4.4 Start-up time

The start-up time of a PC plant with CCS is 2 - 4 hours (hot and warm start). Respectively an NGCC plant starts-up in 1 – 4 hours. Start-up times faster than 2 hours can be difficult to attain due to the time it takes the stripper to warm up into operating temperature. This may limit especially the flexibility of NGCC plants (Brouwer *et al*. 2013).

Hot and warm start of an oxy-combustion plant takes 1.5 – 5 hours in air-firing mode. The full ASU start-up takes up to 36 hours according to Domenichini *et al*. (2013).

4 Methods

4.1 Modelling approach

The research question in this work handles a problem of knowing which emission reduction technologies should be applied at each DH and CHP plant in a single network at a given market situation and at what load these plant should then be operated. An optimisation model is therefore needed to solve this dispatch problem. During the Phase 1, considerable efforts were taken towards this end. First, a spreadsheet cash flow model was built to address the profitability and CO_2 emissions of the case CHP network. The model takes as inputs the techno-economic parameters for each plant and emission reduction technology given in Annex 3 - Annex 6, and the prices and market values of electricity, fuels and emission allowances presented in Annex 2. The CO_2 emissions are calculated based on fuel use using emission factors given in Annex 1. The net cash flow is calculated over 12 periods, where the economic parameters describing the prevailing market scenarios can change. Once the cash flows were modelled, the application of optimisation tools was initiated.

The optimisation goal is to maximise the net cash flow subject to a constraining emission cap and a heat demand of the system. The model variables are load factors and emission reduction technologies of the plants included in the case district heating network. The emission cap is presented as reduction percentage over studied time-frame from a business-as-usual situation without constraints on emissions. Heat demand in the DH network must be met at all times. The case network consists of three CHP plants and one DH plant.

Work on both linear and nonlinear optimisation models were carried out during the Phase 1. Depending on the case assumptions, the optimisation problem can have nonlinear elements. For instance, capital costs of a facility at a certain time period depend on the optimal selection of emission reduction technologies for the same plant at the preceding or following periods if included in the studied time-frame. Another nonlinear element is the effect of plant load factor to net income, which depends on whether the heat demand is fulfilled or the plant operate in CHP mode.

Solving nonlinear problems becomes more difficult as the studied system grows. Even a limited sized problem such as the optimisation of the case CHP system becomes too large to be effectively solved without advanced commercial optimisation tools. As another downside of using a nonlinear optimisation algorithm, the result cannot be guaranteed to represent the global maximum or minimum of the target function (here the maximum of net cash flow). Using an available nonlinear solver[2], the problem was able to be solved when restricted to one time period instead of 12. This serves to fulfil the goals of Phase 1, where optimal emission reduction technologies are assessed for the case CHP system in static market scenarios (see Annex 2).

To assess the research question of the Phase 2, where the flexible operation of CCS plants is assessed in the case CHP system, a linear formulation of the optimisation problem would be highly beneficial. A linear model is guaranteed to find the global optimum and the solution is reached much faster than with nonlinear models. By cutting nonlinear elements from the cash flow model, a linear optimisation algorithm has been applied to the case CHP system. The linear dispatch optimisation model can answer how and in what point of time the necessary emission cuts should be made in the CHP system.

The objective function of the linear optimisation model is given below in Equation 1. The nonlinear model also includes capital and fixed operation & maintenance costs. The income and cost terms represent the net sums of all plants included in the case CHP system over a given period (time step). The cash flow model has 12 periods that can each represent average market values over two hours or a month, depending on the assumptions.

[2] GRG Nonlinear algorithm, Excel Solver.

$$\max\left[\sum_{t}^{12}\begin{matrix}(Income_{Heat}+Income_{Electricity}+Income_{Bio-electricitySubsidies}\\ -Costs_{O\&M\,(Variable)}-Costs_{CO2Capture}-Costs_{EmissionAllowance}-Costs_{Fuel}-Cost_{FossilHeatTax})\end{matrix}\right] \quad (1)$$

The CO_2 capture costs consist of transport and storage costs, amounting to 30 €/tCO_2.

5 Limitations

The results given in this status report represent the work carried out during the Phase 1. They are limited to optimisation of the case CHP system under static market scenarios (see Annex 2). The material and methods describing the CCS system flexibility and linear system optimisation are gathered and assessed for purposes of the work during the Phase 2.

6 Results

Model runs were carried out first for a business-as-usual (BAU) case without an emission cap and then using reduction targets of -50 % CO_2 and -80 % CO_2. Four market scenarios were used, two for CHP production during low market value of electricity and two for condensing operation during peak electricity price. The scenarios are formed by combining: (i) high electricity price and high heat demand, (ii) peak electricity price and high heat demand, (iii) low electricity price and low heat demand and (iv) peak electricity price and low heat demand. The assumed market values of heat, electricity and fuels are given in Annex 2. The result matrix is presented in Table 1.

In the BAU case, where CO_2 emissions are not constrained, all the heat is produced in the CHP plants in every market scenario. Investment to the optional third CFB CHP plant, which is 40 % biomass-fired, seems profitable in all market scenarios except the one assuming a low electricity price and a low heat demand. The coal-fired CHP plant is used for covering the heat demand in the market scenario in question.

Setting a -50 % CO_2 emission cap changes the optimal choice of technologies. During high electricity price and high heat demand, the coal-fired CHP plant is stopped, the NGCC CHP plant is used and the investment to the CFB CHP plant is profitable. Additionally, investment in the DH plant to replace all fuel oil with pyrolysis oil is profitable and the plant is in operation. If peak electricity prices were assumed, all the production would move to the CHP plants and new technologies would be invested in. The coal-firing CHP would be taken into use and retro-fitted with CCS, a fuel switch to 50 % bio-SNG would become profitable in the NGCC CHP plant and the 40 % biomass-firing CFB CHP plant would be again invested in. Assuming low electricity price and low heat demand, only the new biomass co-firing CFB CHP plant would be taken into use. Finally, assuming peak electricity price and low heat demand, the emission reduction would be reached most economically by cutting electricity production and using the coal-fired CHP plant to cover the heat demand.

When the most ambitious emission reduction requirement of -80 % is introduced, the production palette becomes the same in the market scenarios where high heat demand and peak or high electricity prices are assumed. In these scenarios' results, CCS is retrofitted to both PC and NGCC CHP plants, the biomass-co-firing CFB CHP plant is invested in and a fuel switch to 100 % pyrolysis oil is made at the DH plant. Assuming low electricity prices and low heat demand, CCS is retrofitted to the PC CHP plant and the other units remain unused. Regarding the condensing production scenario with peak electricity price and low heat demand, the emission reduction requirement is met again only by cutting electricity production compared to the BAU case and using only the PC CHP plant to answer the heat demand.

Table 1. Lowest emission reduction technologies in various market situations and emission reduction schemes.

	BAU	-50% CO_2 cap	-80% CO_2 cap
CHP production	Coal CHP	Biomass-40% CHP	Coal CCS CHP
(high electricity price + high heat demand)	Gas CHP	Gas CHP	Gas CCS CHP
	Biomass-40% CHP	Bio-Oil DH	Biomass-40% CHP
			Bio-Oil DH
Condensing production	Gas CHP	Coal CCS CHP	Coal CCS CHP
(peak electricity price + high heat demand)	Biomass-40% CHP	Bio-SNG-50% CHP	Gas CCS CHP
	Coal CHP	Biomass-40% CHP	Biomass-40% CHP
			Bio-Oil DH
CHP production	Coal CHP	Biomass-40% CHP	Coal CCS CHP
(low electricity price + low heat demand)			
Condensing production	Coal CHP	Coal CHP	Coal CHP
(peak electricity price + low heat demand)	Gas CHP		
	Biomass-40% CHP		

7 Validation of results

The results were obtained by using a nonlinear optimisation algorithm, which has a risk of converging to a local maximum of net cash flow instead of the global maximum. By careful testing and selection of solver parameters, the results seem quite reliable in the restricted problem size applied.

The results completely depend on the case assumptions, which may evolve and change over the course of the Phase 2. Therefore, it may not be fruitful to further validate the results more than judge the results as a model experiment. Efforts should be directed at better defining the model inputs, the case CHP system, emission reduction technologies and the plant operating modes to best reach the ultimate goal of the work.

8 Conclusions

A cash flow model of a case CHP system has been built and an optimisation problem defining the most profitable emission reduction technologies and load factors for the included plants has been formulated. The case CHP system consists of a coal- and a gas-fired CHP plant, a biomass-co-firing circulating fluidised bed CHP plant as an optional investment and an oil-fired district heating plant. The optimisation problem has been solved for four static market scenarios comparing two emission reduction requirements against the business-as-usual situations. When -50 % CO_2 emissions were required, CCS emerged as a profitable emission reduction technology for the coal-fired CHP plant in the market scenario with peak electricity price and high heat demand. Assuming an emission reduction requirement of -80 % compared to business-as-usual situation, CCS was widely applied in the system.

Literature references on the flexibility of CO_2 capture in CHP environment are few. Be that as it may, more research results are available for CCS flexibility in power production. Based on a literature review, capture of CO_2 in general does not seem detrimental to a power plant's start-up times, ramp rates, part-load efficiencies and minimum load levels. Oxy-combustion plants seem to suffer from slower ramp rates and longer start-up times, however. It will be interesting to assess the possible positive effect of flexible use of CO_2 capture to the CHP system's net profitability during the Phase 2 of the work. However, further optimisation model development is still necessary.

8.1 Next steps within CCSP program

The work will continue as planned for the Phase 2, concentrating on the analysis of the effects of CCS in the future CHP system. The market scenarios are adjusted to represent views on future production and demand. A higher share of renewable electricity is assumed, increasing the demand for peak load capacity. As the work focuses more on the flexibility of CCS in CHP production, economic scenarios will consist of hourly level market assumptions.

9 References

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10 Annexes

Annex 1. Fuel emission factors.

	$kgCO_2/kWh,fuel$
Coal	0,31304
Natural gas	0,18404
Biogas	0,00000
Fuel oil	0,24555
Bio-oil	0,00000
TOP	0,00000
Pellet	0,00000
Forest residues	0,00000
Woodchips	0,00000
Energy crops	0,00000

Annex 2. Market scenarios.VAT excluded.

	CHP production (high electricity price + high heat demand)	CHP production (low electricity price + low heat demand)	Condensing production (peak electricity price + low heat demand)	Condensing production (peak electricity price + high heat demand)
Electricity price [€/kWh]	0,042 €	0,037 €	0,090 €	0,090 €
Heat price [€/kWh]	0,045 €	0,025 €	0,025 €	0,045 €
Emmission allowance price [€/tCO2]	5,000 €	5,000 €	5,000 €	5,000 €
Fuel price Heavy Fuel Oil [€/kWh]	0,062 €	0,062 €	0,062 €	0,062 €
Fuel price Coal [€/kWh]	0,010 €	0,010 €	0,010 €	0,010 €
Fuel price Natural gas [€/kWh]	0,040 €	0,040 €	0,040 €	0,040 €
Fuel price Biogas [€/kWh]	0,063 €	0,063 €	0,063 €	0,063 €
Fuel price Pellet [€/kWh]	0,036 €	0,036 €	0,036 €	0,036 €
Fuel price TOP [€/kWh]	0,040 €	0,040 €	0,040 €	0,040 €
Fuel price Bio-oil [€/kWh]	0,090 €	0,090 €	0,090 €	0,090 €
Fuel price Forest residues [€/kWh]	0,020 €	0,020 €	0,020 €	0,020 €
Fuel price Woodchips [€/kWh]	0,022 €	0,022 €	0,022 €	0,022 €
Fuel price Energy crops [€/kWh]	0,020 €	0,020 €	0,020 €	0,020 €

Annex 3. Coal CHP plant input parameter table.

Emission reduction technology	-	PEL-7%	BIO-40%	CCS
Fixed CAPEX [€/period]	0 €	123 649 €	779 436 €	4 554 190 €
O&M [€/kk]	63 253 €	64 489 €	71 047 €	108 795 €
O&M [€/kWh fuel]	0,0010 €	0,0010 €	0,0010 €	0,0010 €
Share of accountable CO2 emissions captured [%]	0 %	0 %	0 %	90 %
CO2 transport & storage [€/tCO2]	30,00 €	30,00 €	30,00 €	30,00 €
Tax for heat from fossil fuels [€/kWh,heat]	0,01 €	0,01 €	0,01 €	0,01 €
Subsidy for power from biomass [€/kWhel]	0,00 €	0,00 €	0,00 €	0,00 €
Coal in fuel mix [%]	100 %	93 %	60 %	100 %
Natural gas in fuel mix [%]	0 %	0 %	0 %	0 %
Biogas in fuel mix [%]	0 %	0 %	0 %	0 %
Fuel oil in fuel mix [%]	0 %	0 %	0 %	0 %
Bio-oil in fuel mix [%]	0 %	0 %	0 %	0 %
TOP in fuel mix [%]	0 %	0 %	10 %	0 %
Pellet in fuel mix [%]	0 %	7 %	10 %	0 %
Forest residues in fuel mix [%]	0 %	0 %	10 %	0 %
Woodchips in fuel mix [%]	0 %	0 %	10 %	0 %
Energy crops in fuel mix [%]	0 %	0 %	0 %	0 %
Emissions [kgCO2/kWh,fuel]	0,31	0,29	0,19	0,03
CO2 transport & storage costs [€/kWh,fuel]	0,00 €	0,00 €	0,00 €	0,01 €
Tax cost per heat output [€/kWh,heat]	0,01 €	0,01 €	0,01 €	0,01 €
Subsidy income per electric output [€/kWhel]	0,00 €	0,00 €	0,00 €	0,00 €
Overall efficiency [%]	91 %	91 %	91 %	81 %
Electric output [MW]	362	354	223	326
Heat output [MW]	720	704	444	648

Annex 4. Gas CHP plant input parameter table.

Emission reduction technology	-	BioSNG-50%	CCS
Fixed CAPEX [€/period]	0 €	1 453 291 €	5 231 847 €
O&M [€/kk]	43 599 €	58 132 €	95 917 €
O&M [€/kWh fuel]	0,0010 €	0,0010 €	0,0010 €
Share of accountable CO2 emissions captured [%]	0 %	0 %	90 %
CO2 transport & storage [€/tCO2]	30,00 €	30,00 €	30,00 €
Tax for heat from fossil fuels [€/kWh,heat]	0,01 €	0,01 €	0,01 €
Subsidy for power from biomass [€/kWhel]	0,00 €	0,00 €	0,00 €
Coal in fuel mix [%]	0 %	0 %	0 %
Natural gas in fuel mix [%]	100 %	50 %	100 %
Biogas in fuel mix [%]	0 %	50 %	0 %
Fuel oil in fuel mix [%]	0 %	0 %	0 %
Bio-oil in fuel mix [%]	0 %	0 %	0 %
TOP in fuel mix [%]	0 %	0 %	0 %
Pellet in fuel mix [%]	0 %	0 %	0 %
Forest residues in fuel mix [%]	0 %	0 %	0 %
Woodchips in fuel mix [%]	0 %	0 %	0 %
Energy crops in fuel mix [%]	0 %	0 %	0 %
Emissions [kgCO2/kWh,fuel]	0,18	0,09	0,02
CO2 transport & storage costs [€/kWh,fuel]	0,00 €	0,00 €	0,00 €
Tax cost per heat output [€/kWh,heat]	0,01 €	0,01 €	0,01 €
Subsidy income per electric output [€/kWhel]	0,00 €	0,00 €	0,00 €
Overall efficiency [%]	92 %	92 %	82 %
Electric output [MW]	631	631	568
Heat output [MW]	612	612	551

Annex 5. CFB CHP plant input parameter table.

Emission reduction technology	Not included	BIO-40%
Fixed CAPEX [€/period]	0 €	4 490 714 €
O&M [€/kk]	0 €	44 907 €
O&M [€/kWh fuel]	0,0000 €	0,0010 €
Share of accountable CO2 emissions captured [%]	0 %	0 %
CO2 transport & storage [€/tCO2]	0,00 €	30,00 €
Tax for heat from fossil fuels [€/kWh,heat]	0,00 €	0,01 €
Subsidy for power from biomass [€/kWhel]	0,00 €	0,00 €
Coal in fuel mix [%]	100 %	60 %
Natural gas in fuel mix [%]	0 %	0 %
Biogas in fuel mix [%]	0 %	0 %
Fuel oil in fuel mix [%]	0 %	0 %
Bio-oil in fuel mix [%]	0 %	0 %
TOP in fuel mix [%]	0 %	10 %
Pellet in fuel mix [%]	0 %	10 %
Forest residues in fuel mix [%]	0 %	10 %
Woodchips in fuel mix [%]	0 %	10 %
Energy crops in fuel mix [%]	0 %	0 %
Emissions [kgCO2/kWh,fuel]	0,31	0,19
CO2 transport & storage costs [€/kWh,fuel]	0,00 €	0,00 €
Tax cost per heat output [€/kWh,heat]	0,00 €	0,01 €
Subsidy income per electric output [€/kWhel]	0,00 €	0,00 €
Overall efficiency [%]	0 %	88 %
Electric output [MW]	0	240
Heat output [MW]	0	410

Annex 6. Oil DH plant input parameter table.

Emission reduction technology	-	BIO-OIL-5%	BIO-OIL
Fixed CAPEX [€/period]	0 €	250 319 €	119 199 €
O&M [€/kk]	25 722 €	28 225 €	26 914 €
O&M [€/kWh fuel]	0,0010 €	0,0010 €	0,0010 €
Share of accountable CO2 emissions captured [%]	0 %	0 %	0 %
CO2 transport & storage [€/tCO2]	30,00 €	30,00 €	30,00 €
Tax for heat from fossil fuels [€/kWh,heat]	0,01 €	0,01 €	0,01 €
Subsidy for power from biomass [€/kWhel]	0,00 €	0,00 €	0,00 €
Coal in fuel mix [%]	0 %	0 %	0 %
Natural gas in fuel mix [%]	0 %	0 %	0 %
Biogas in fuel mix [%]	0 %	0 %	0 %
Fuel oil in fuel mix [%]	100 %	95 %	0 %
Bio-oil in fuel mix [%]	0 %	5 %	100 %
TOP in fuel mix [%]	0 %	0 %	0 %
Pellet in fuel mix [%]	0 %	0 %	0 %
Forest residues in fuel mix [%]	0 %	0 %	0 %
Woodchips in fuel mix [%]	0 %	0 %	0 %
Energy crops in fuel mix [%]	0 %	0 %	0 %
Emissions [kgCO2/kWh,fuel]	0,25	0,23	0,00
CO2 transport & storage costs [€/kWh,fuel]	0,00 €	0,00 €	0,00 €
Tax cost per heat output [€/kWh,heat]	0,01 €	0,01 €	0,00 €
Subsidy income per electric output [€/kWhel]	0,00 €	0,00 €	0,00 €
Overall efficiency [%]	80 %	80 %	80 %
Electric output [MW]	0	0	0
Heat output [MW]	2 200	2141	1020